New York Independent System Operator

Request for Information

on

Equipment, Software, & Systems Integration Services

for

Statewide Synchronized Phasor Measurement System, Wide-Area Situational Awareness Applications, & Smart Grid Enabled Capacitor Systems

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1.0 Introduction

1.1 Purpose

The New York Independent System Operator (NYISO) and New York Transmission Owners (TOs) are deploying a Phasor Measurement Network (PMN) capable of achieving complete situational awareness of the New York bulk electric system (BES) and Smart Grid enabled capacitors (the "Project"). The PMN will be integrated with a visualization subsystem, an energy management system (EMS), historical information subsystem, and other PMNs. This request for information (RFI) is to assist in the development of the technical and functional requirements for the PMN. The technical requirements will encompass intelligent electronic devices (IEDs) capable of performing synchronized phasor measurements, including phasor measurement units (PMUs), phasor data concentrators (PDCs), super phasor data concentrators (SPDCs), EMS enhancements, communications and associated applications.

The technical and functional requirements developed from the information obtained through this RFI will be used to procure the PMN equipment, components, applications, and integration services through competitive solicitation facilitated through one or more Requests for Proposals (RFPs).

This Project is partially funded by the Department of Energy Smart Grid Investment Grant, an American Recovery and Reinvestment Act (ARRA) funded program.

1.2 About the NYISO

The NYISO is at the heart of New York State's electric system, operating the high-voltage transmission network, administering and monitoring New York's wholesale electricity markets, and planning for the State's energy future.

The TOs are comprised of the following entities:

(i) Central Hudson Gas & Electric Corporation;

(ii) Consolidated Edison Company of New York, Inc.;

(iii) New York State Electric & Gas Corporation;

(iv) Niagara Mohawk Power Corporation d/b/a National Grid;

(v) Orange and Rockland Utilities, Inc.;

(vi) Rochester Gas and Electric Corporation;

(vii) the Power Authority of the State of New York, a corporate municipal instrumentality of the State of New York ("NYPA"); and

(viii) The Long Island Lighting Company d/b/a LIPA (a subsidiary of the Long Island Power Authority, a corporate municipal instrumentality of the State of New York) ("LIPA") through its agent National Grid Electric Services LLC d/b/a National Grid.

1.3 System Overview

This Project will provide the foundation for and enable future developments of a smart grid infrastructure (SGI) in the New York bulk electric system (BES). The objective of the Project is to enhance the reliability of the New York Control Area's (NYCA's) BES and to improve the efficiency of the New York power delivery system.

The Project is comprised of three parallel tracks. One of the Project tracks will deploy a statewide, open, flexible, interoperable, secure, and expandable PMN system that will work in concert with the existing control and monitoring systems. The PMN system will operate using standard information models and communication protocols. The PMN system will enhance the ability to detect system vulnerabilities and disturbances in real-time and to potentially mitigate their impact. The scope of work associated with this Project track involves the installation of PMUs by each of the TOs within their respective transmission districts and the integration of those devices with their energy control centers and the NYISO's control centers. The TOs intend to engage multiple vendors to purchase, install, and integrate their PMUs with the PMN.

In the second Project track, system design studies will be conducted to optimally site sources of PMU information within the PMN, determine communication requirements, and develop system planning and operations protocols to leverage data from the PMUs. Vendors will deploy a suite of wide-area situational awareness software at the NYISO's control centers to serve as the platform for the PMN.

The third Project track involves the integration of new reactive power sources through the installation of additional shunt capacitors by Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas and Electric Corporation within their respective transmission districts. These smart grid enabled devices will enhance the control and coordination of the voltage profile on the New York power grid resulting in improvements to the efficiency and reliability of the New York power grid. These switched/controllable capacitor banks will provide additional reactive power resources to the bulk power system during system conditions where and when it is needed the most. The TOs

may engage multiple vendors to purchase, install, and integrate the capacitor banks with their respective SGI.

The Project will provide for enhanced functionality through the deployment of smart grid technologies throughout New York State in the electric transmission system topic area as follows.

- This Project consists of the deployment of an NYCA-wide, open, flexible, interoperable, secure, and expandable PMN system that will be integrated with existing monitoring and, potentially, control systems. The PMN system will operate using standard information models and communication protocols and will be an integral part of an interconnection-wide synchrophasor network. The New York TOs will strategically install synchronized PMUs, with optional substation PDCs, and PDCs at their respective control centers. The TOs will also provision the necessary communication and networking equipment and facilities to transmit synchrophasor data to PDCs installed by the NYISO at their control centers.
- The NYISO will deploy synchrophasor measurement-based functions, such as monitoring of small signal oscillations, damping, voltage stability, and angular separation; voltage, current, frequency, and phase angle, as well as other functions, including enhanced state estimation, system model calibration, and a study to analyze opportunities for controlled system separation.
- The TOs will integrate new reactive power sources through the installation of additional Smart Grid enabled shunt capacitors. These switched/controllable capacitor banks will provide for additional reactive power resources that will improve power delivery system efficiency through improved voltage profiles and the reduction of system losses.

1.4 Project Conceptual Overview

1.4.1 SGI System Components

The functional SGI system configuration overview depicted in Figure 1 shows the major components of the PMN added to the existing operational environment. This Project is to integrate the phasor measurement system with the existing EMS and an updated Visualization subsystem to include phasor functions analysis and other data streams. Each of the subsystems is functionally defined in the following. The existing EMS will be expanded to use phasor measurements for all applications, especially State Estimation.

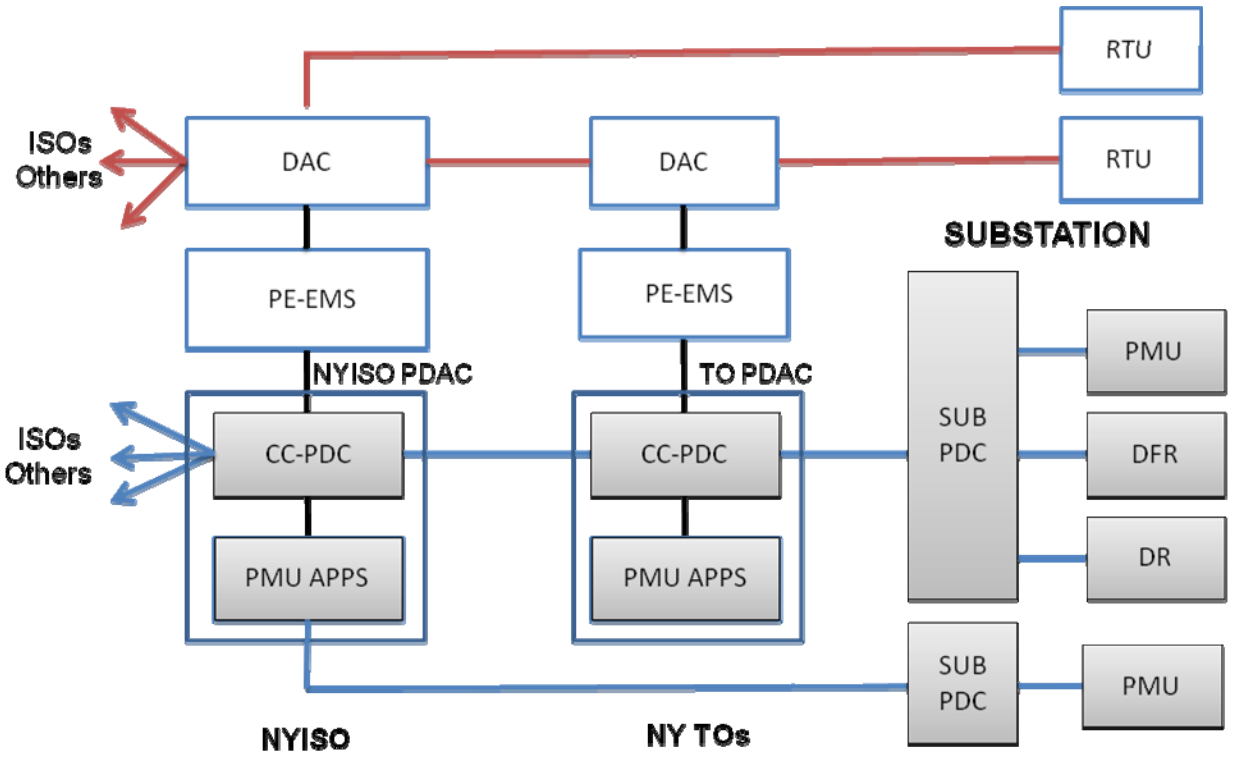

Figure 1: SGI Overview

The integration of the PMN with the other subsystems will be labeled as the SGI system.

The system configuration shown is one depiction of an integrated composite system. Vendors are encouraged to propose alternative designs to demonstrate the capabilities of their components, additional system flexibility of their subsystems, and scalability for extended future growth capability.

The composite system is expected to include several application functions at the uppermost PMN level. Several designs label this level as a Super PDC, Master PDC, or Control Center PDC. This representation uses the term Phasor Data Acquisition and Control (PDAC) as there are multiple applications that are expected to reside at this level. It is thus expected that a platform far in excess of a data concentrator would be needed to support these functions. The functions planned as part of this procurement are listed, as well as functions that may be included in the future. Vendors should provide information on the capability of their products to provide such functional support or an alternative architecture to provide the same functional capability.

The visualization subsystem is to provide a complete situational awareness view to BES operators beyond the traditional EMS one-line and tabular displays. The visualization system is described in the following and may or may not be a part of the existing EMS system. The visualization system is to enable integration of the traditional EMS displays with phasor data and with calculations based on phasor data to provide additional operational information.

The composite system is expected to be interconnected with other energy control centers and PMNs. Vendors should provide information on the limitations of such interconnection, the level at which such interconnections are supported, the capabilities of existing or planned equipment, and how such interconnections may be expanded. The NYISO expects to integrate this system with the systems at each Transmission Owner and at each adjacent Independent System Operator.

It is expected that PMUs and PDCs at the generation sites will eventually be added.

This SGI system shall support the scope of deployment proposed through this Project and the future expansion, evolvement, and integration as part of an overall Smart Grid rollout effort. Therefore, this system must:

- Deliver the initial functionality described in this document,
- Be flexible enough to scale to support the data growth described above, and
- Remain consistent with the present industry architectural vision of the Smart Grid.

Although some components in the overall description may not be included in the initial deployment, the architecture shall take the future integration and migration to this overall Smart Grid system architecture into consideration.

1.4.2 Smart Grid Enabled Capacitor System Components

The TOs will integrate new reactive power sources into the NYCA through the installation of additional Smart Grid enabled shunt capacitors. These switched/controllable capacitor banks will be installed on the distribution and transmission systems, and will provide for additional reactive power resources that will improve power delivery system efficiency through improved voltage profiles and the reduction of system losses.

1.5 Structure of this Request for Information

This request for information (RFI) is to provide the basis for the request(s) for proposal(s) (RFP) that will be used to procure the PMN, software applications, associated integration services, and Smart Grid enabled capacitor systems. The RFP(s) are expected to be issued in either the fourth quarter of 2010 or the first quarter of 2011. The RFI is composed of two items. The first item is this document that describes the overall project, the expected architecture, and the functions that are required currently or expected within the lifetime of the project equipment. The second item is a spreadsheet. The associated spreadsheet should be used for providing the requested information listed in the appendices. The spreadsheet will be used to quickly understand the capabilities and the quality of each vendor. This project is to consist of equipment and systems that are ready for deployment.

2.0 System Requirements

2.1. PMN System Requirements Summary

The PMN will include the field devices to sensor and to compute the phasor values at a rate to be defined. The system is expected to function over a ten (10) year period as the number of phasor measurements increase each year. The equipment to sensor and convert the data is not to be based on any one manufacturer but will be based on various manufacturers as awarded by the NYISO and the various Transmission Organizations.

2.2. SGI System Requirements for Current Deployment

The general synchrophasor system installation for a utility would consist of several Phasor Measurement Equipment (PME) devices installed in substations, a Phasor Data Concentrator device installed in each substation, and a Control Center Phasor Data Concentrator (CCPDC) installed in the control center. The CCPDC would then dispense the data to various applications, including visualizations, historians, and control and protection applications. The system would also incorporate a fast, reliable and secure communication network for data transfer, and for control actions/commands to flow to the various controlled equipment.

The applications also include post-mortem analysis tools to allow the system operator to reproduce/replay the archived data records and be able to perform a cause/effect analysis.

The system must also allow reasonable system expansion for the foreseeable future, to allow for equipment upgrades, modernization and other system enhancements.

2.3. SGI System Requirements for Future Expansion/Integration

The system is to be expandable to perform all future functions as listed with PMU data gathered from the expansion list. The system should be open to migration to an alternative energy management system when it is decided to retire the existing EMS.

2.4. PME Field Devices

This section focuses on the functionality and data flow requirements of each SGI component in the Field Devices subsystem. The system will consist of several field devices, including Phasor Measurement Equipment and Phasor Data Concentrators. The following minimum requirements are required from Vendor's systems.

2.4.1 PME Function

Phasor Measurement Equipment may be any device that is capable of producing a synchrophasor (as defined by the IEEE standard C37.118-2005). Such devices may include PMUs (Phasor Measurement Units) or SMUs (Synchronized Measurement Units). They may also include

DFRs (Digital Fault Recorders) or conventional relays that are enabled to make such synchronized measurements.

The main purpose of the phasor measurement technology is to make simultaneous, synchronized measurements of system variables, such as voltages, currents and their associated angles over a widely separated network, to permit an accurate view of the entire system. In the absence of this technology, local measurements of power systems quantities (or, unsynchronized measurements of remote quantities) do not generally allow an accurate picture of the state of the system. This prevents implementation of accurate remedies to evolving wide area events. With an accurate picture of the entire system due to synchronized measurements and fast data networks, better remedies can be implemented and the overall stability/reliability of the network can be improved.

2.4.2 Phasor Data Concentrator (PDC) Function

PDCs are devices that collect synchrophasor data from PME and collate/align them for transmission to control centers. Typically, a PDC would be installed in a substation so that the synchrophasor data from all of the PME in a substation would be sent as one data packet to the control center. Without the PDC, the control center may have too much of an administrative task on its hands, with perhaps hundreds of PMUs to be handled across the network.

PDCs also perform the task of hosting any substation level application functions that may need the data from the specific substation, and in effect, can become a host to a network of distributed application functions identified as Smart Grid capable.

2.5. Phasor Data Acquisition and Control (PDAC)

This section focuses on the functionality and data flow requirements of each SGI component in the PDAC subsystems located at the Grid Control Center (GCC). It is envisioned that some applications requiring a large amount of phasor data may be processed at this level.

PDAC subsystems receive data streams from substation internal PDCs, PMUs and external PDCs. The phasor data streams are packets of data representing a sample of system measurements with a time-tag applied precisely when the sample was taken. The packets are sent continuously via a communication channel to the PDC.

PDAC subsystem correlates synchrophasor data by time-tag to create a system-wide time synchronized measurement set. PDAC subsystem also provides some simple synchrophasor data quality checks, monitors the overall measurement system with performance records, and displays.

Located at the NYISO Control Centers (GCC), PDAC subsystems will interface with GCC SGI LAN and NYISO SGI WAN to receive synchrophasor data from a number of PDCs/DFRs/PMUs installed in NYISO grid. PDAC subsystems may also receive synchrophasor data from a number of external PDCs through NERCnet, ISOnet or NASPInet. The PDC

function of PDAC subsystems correlate the received data according to their time tag, generates a time-aligned aggregated data stream, and feeds the time-aligned data either to some application directly, or to a Data Management subsystem for more comprehensive data validation and quality check. After validation and quality check, the data will be streamed to some applications, and also stored in the SGI Real-Time and Historian databases for use by SGI applications. Time-aligned data could also be sent to other participating utilities or Independent System Operators in the North East. Any utility's data can be identified by the ID for the PDC that is embedded in the data, or by device IP address.

The communication link used for data flow between PDAC and PDCs/DFRs/PMUs is a secured NYISO IP WAN network (IPv6 but may start as IPv4) for SGI and the PMU data packets are transmitted in UPD/IP format.

3.0 Application Functions Considered

SGI will provide a number of wide-area analysis, control, and situational awareness applications to support both real-time decision making and post-event analysis. It is expected that some will reside within the EMS and others will be distributed to reside in that part of the system providing the most efficient use of computational capability.

The wide-area situational awareness applications that need to be supported by Vendor's application in the current deployment must include the following:

Voltage phase angle monitoring,

Voltage stability monitoring,

Low frequency oscillation monitoring,

Fault location, and

Post-event analysis application.

In addition, a number of supporting applications may be included in the current deployment.

1. DFR records retrieval application.

Global DFR event trigger management application.

Wide-area event detection application.

All situation awareness applications shall support the following basic functionalities:

1. Warnings and alarms generation,

Trending,

Compliance reporting,

The applications that need to be supported are listed in the following subsections.

3.1 Voltage Phase Angle Monitoring (VPAM)

The voltage phase angle differences between different buses are important system parameters. They are accurate indicators of power flow and system stability. Real-time monitoring of these parameters should be a significant contributor towards corrective actions. This application allows the user to monitor the phase angle differences between multiple buses and a selectable reference bus in the system where PMUs are installed. The application should generate warnings/alarms for the monitored voltage phase angle differences when preset limits are exceeded.

3.2 Voltage Stability Monitoring (VSM)

Voltage Stability is the ability of an interconnected power system to maintain acceptable voltages at all applicable load buses under normal and abnormal conditions. Interconnected systems on the Western, Eastern and ERCOT Interconnections comply by meeting North American Electric Reliability Corporation (NERC) voltage and reactive control reliability standards and system performance planning standards under both normal and contingency conditions. NERC balancing areas balance generation and load while ensuring voltage levels, reactive flows and reactive resources are monitored and maintained within limits to protect equipment and maintain the reliable operation of the interconnection. The goal of the interconnection is to deliver energy to fluctuating loads at applicable buses without allowing the voltage to drop below nominal operating levels. If a bus is loaded beyond its limit, the system voltage becomes unstable causing circuit breakers to trip. This loading limit depends on the system conditions and varies from situation to situation. The objective of the voltage stability monitoring application is to provide a real-time online tool for assessing the power system reliability margin with respect to voltage stability from phasor measurement data. The outcome should assist bulk power operators to take pre-emptive remedial measures thereby preventing voltage instability and furthermore voltage collapse linked to cascading failures of the system.

3.3 Low Frequency Oscillation Monitoring (LFOM)

Each system has some natural oscillation frequencies. When the system is excited with a disturbance such as a fault, it works as an impulse to the system and the oscillating modes reflect in the measured quantities. Depending on the observability of the modes of oscillation in the measurement, the modes can be detected by spectral analysis or other means. The corresponding frequency and damping of each mode can be calculated using different algorithms. If the damping ratio is lower than 5% it is considered a poorly damped system where the oscillation may continue for a prolonged duration causing other undesirable events to happen. The low

frequency oscillation monitoring application should provide the information in real time so that corrective actions can be taken. The low frequency oscillation detection application normally identifies the low frequency oscillation present in an event if it falls under the range of interest (typically the low frequency range should be user selectable and lies within 0.1 Hz to 2 Hz). This helps to identify the critical poorly damped modes so that the operator can make decisions on re-dispatch or some other means to alleviate the small signal stability problem.

3.4 Fault Location (FL)

A fault is an abnormal condition in a power system. Fast fault detection and isolation by protective relays are critical to the overall power system health. However, isolating a faulted line may disconnect customers and reduce the system's transfer capability. Thus, this should be restricted to affect as few customers as possible, and for as short a time as possible. Fast and reliable fault location can assist the fast repair and restoration of an isolated line. This application is for quickly and accurately identifying and locating a fault after it occurs.

SGI shall provide a suite of power system FL functions. The FL functions comprise a set of tools for faulted lines identification and accurate fault location calculations. The FL functions are post-fault analysis applications. The FL application should be functionally designed to accommodate, at a minimum, the following.

3.5 Post-Event Analysis (PEA)

An event is an abnormal situation in the power system that may create an abnormal voltage, current or power flow change in different buses or nodes in the system. The event can be due to a temporary or a permanent fault, a switching event such as capacitor switching, abnormal loading, generation surplus or deficiency, etc. The PEA application shall allow the user to identify, locate and analyze an abnormal situation from recent/historical recorded data. It allows a replay of event data for a specified time span. It should allow different analyses to be performed simultaneously on the data available in the database and should have the ability to identify any event from recorded data to isolate the time span when some event has taken place. It analyzes the recorded data of voltage/current magnitudes, phase angles at different buses, breaker operations, etc. to generate user-specified identification of events. It helps to identify the precise time at which the abnormal event occurred and the sequence of preceding events, leading to determining the cause of the incidence. Hence, it could provide some information on how the situation could have been averted. Faults and other disturbances are typical for a power system. Although they can't be avoided, the attempt is to devise a system so that these disturbances do not create a critical failure, thereby preventing power delivery to the customer. PEA can provide an insight into the problems that the system may have had leading to the incidence. The analysis

helps to identify those problems and can help to mitigate and prevent those problems in the future.

3.6 DFR Records Retrieval (DFRRR)

The records of phasor measurements associated with any DFR should be accessible through the Data Management subsystem.

3.7 Global DFR Event Trigger Management

The records of phasor measurements associated with any predefined global event should be accessible through the Data Management subsystem.

3.8 Wide-area Event Detection

The occurrence of any event predefined as a wide-area event should be accessible through the Data Management subsystem.

3.9 Future Advanced Applications

The system should be able to enable more advanced applications to assist Real-Time Wide-Area Operation, Control, and Protection in the future.

4.0 SGI Cyber Security Requirements

The SGI should comply with all applicable NERC and NIST cyber security requirements. The NYISO conducts a Vendor Assessment to assist in determining such compliance. All Vendors are required to complete the NYISO's Vendor Assessment Questionnaire, provided hereto in Appendix E, which will be used in the assessment of all Vendors.

5.0 RFI Response Instructions

5.1 Correspondence

Please direct all questions, correspondence, and responses related to this RFI to **mrubin@nyiso.com,** with "NYISO SGI RFI" included in the subject line.

5.2 RFI Schedule

The schedule for this RFI is:

- Release RFI — Wednesday, July 21, 2010
- RFI Responses Due — Friday, August 20, 2010 @ 3:00 PM EDT

5.3 RFI Response Format

5.3.1 Cover Letter

The cover letter shall be in the form of a standard business letter and shall be signed by company interested to supply equipment to NYISO SGI project.

5.3.2 Responses to Questions

The answers to the Questions should be provided as a digital attachment to the cover letter using the applied spreadsheet.

5.3.3 Response Format

The cover letter and other supplemental attachments should be provided in either MS Word (versions 2007 or '97-2003') or Adobe Acrobat format.

5.4 Documentation

Any documentation submitted as a response to this RFI shall become NYISO property and will not be returned. Any proprietary or confidential information provided by respondents to this RFI should be clearly labeled as such to prevent disclosure.

5.5 No Commitment

Neither this request for information nor any other written or oral information made available to any potential bidder or any other person or party or their respective representatives, agents, or advisors form the basis of any offer or contract. Rather, any information regarding the project or any part thereof will give rise to contractual obligations only if and when final agreements have been executed in writing by the parties thereto.

Small businesses, minority-owned and women-owned firms are encouraged to respond to this request for information and larger firms are encouraged to associate with small businesses, minority-owned, and women-owned firms.

NYISO will not reimburse responders for expenses that are incurred as a result of responding to this RFI.

Appendix A – Response Questions

The respondent is to address all of the issues identified in the previous sections. The respondent is to answer the following questions with as much detail as possible. The respondent is to ensure that answers provided are relevant to the Project. List specific projects and provide details on that project when appropriate to the previous concepts or to the individual questions that follow.

The respondent is to answer questions that reflect their expertise and experience for equipment and components. Respondents are not required to, nor necessarily expected to, answer all questions if such questions are inappropriate to their offerings. A yes/no or numeric answer is expected. If additional information is provided, then the column adjacent should list the linked document.

A.1 General

1. Provide a general description of your company.
2. What types of equipment could your company supply for PMN project? List each type of equipment in the following category – PMU, PDC, applications, capacitor, system integrators, etc.
3. Will you possibly subcontract to another vendor or contract other vendors as a subcontractor?
4. Any additional info about your company relevant to this RFI?

A.2 PMN System Requirements Summary

1. Is your system scalable to support future system expansion – this includes both hardware and software applications with capability to scale up to accommodate the rapid increase of substations with new measurement sources anticipated in next ten years and beyond?
2. Is your equipment and system adaptable to interoperability and cyber security standard evolvement over the life span of the system?
3. Is your system capable of providing support for regional (i.e., NPCC, NERC, NYSRC, and EI) functions (e.g., post mortem fault analysis)?
4. Can your system handle data sharing with other ISOs/RTOs, EIs, etc.?
5. Does the system support the following applications at NYISO's control center?
    a. Situational awareness and visualization;
    b. Voltage stability monitoring;

c. State estimation update at the EMS level;
d. Calibration of system planning and operations models; and
e. Controlled system separation.

6. Is the system architecture flexible to support easy addition of future applications?

A.3 General SGI System Requirements

The vendor is to identify by an answer of (Yes/No) or a more detailed response if the future proposed offering will satisfy the following general SGI system requirements.

1. SGI, including DFR/PMU, PDAC, situation awareness applications, shall be a production system with full vendor support. (Yes/No)

2. SGI shall be a highly reliable and secure system with backup redundancies. The system shall continue to function in the case of any single point/location of failure. (Yes/No)

3. The PDAC, databases and SGI applications software shall be able to support NYISO operations at either main CC or backup CC locations of NYISO. (Yes/No)

4. The PDAC, databases and SGI applications software should satisfy the following requirements:

    a. They shall be able to accommodate gradually increased number and types of phasor measurement devices. (Yes/No)
    b. They shall be able to accommodate gradually increased amount of external phasor measurement data exchanges. (Yes/No)

5. The PDAC shall have modular characteristics (performance/processing power, and/or network interfaces), to allow for accommodating system expansion in the numbers of PMUs and DFRs installed. (Yes/No)

6. SGI shall be able to guarantee the Quality of Service (QoS) for SGI applications initially deployed and shall be able to expand and upgrade to guarantee the QoS for future SGI applications. (Yes/No)

7. SGI shall be expandable to meet NERC's CYBER SECURITY compliance requirements. (Yes/No)

8. SGI shall be capable of distinguishing, labeling, and segmenting data from external (non-NYISO) sources. (Yes/No)

9. SGI shall be capable of operating with no external data, continuing to perform all major functions not fundamentally based on said data (Yes/No)

10. SGI shall be capable of distinguishing, labeling, and segmenting specific types or classes of external data (e.g., weather vs. NASPInet) (Yes/No)

11. SGI shall be an open system supporting system interoperability standards to the extent required and possible. (Yes/No)

12. SGI shall include adequate data storage capacities at different levels or components of the system to prevent data loss and ensure adequate historical data availability for planning and engineering as well as operation analysis. The data storage shall include the following:

    a. Data stored at the device and component level (e.g., PMU/DFR, PDC) for internal component functions and as a memory buffer to prevent data loss in case of temporary communication failures. (Yes/No)
    b. Real-time data imbedded with the SGI applications to provide the necessary performance of the applications. (Yes/No)
    c. Online historical data to facilitate fast and secure access to historical data for planning, engineering and operation analysis, such as post-disturbance investigations. (Yes/No)
    d. Offline historical data archive to keep data over long period of time without affecting the data access performance of the online historical data store. (Yes/No)

A.4 SGI System Requirements for Current Deployment

The system requirements for SGI initial deployment (i.e., within the scope of the initial RFP) can be summarized as follows.

1. Is the vendor able to supply production grade Control Center Systems (CCS) at control centers that include PDAC, application servers, visualization and presentation servers, and data storage and archiving subsystems? (Yes/No)

2. Does the vendor have capability to install SGI in four computing environments:

    a. Dispatcher Training System and/or Production (including cluster or failover backup systems)? (Yes/No)
    b. Development? (Yes/No)
    c. Testing? (Yes/No)
    d. Staging/System Test/Training? (Yes/No)

3. Can the vendor provide reliable high-speed communication network between DFR/PMU and PDAC? (Yes/No) What is the expected communication speed envisioned by the vendor?

4. Is the high speed secure network in compliance with NERC CYBER SECURITY requirements? (Yes/No)

5. Is the hardware and software open to future system expansion/upgrade, application addition, performance and security improvement? (Yes/No)

6. Can the vendor system support current DFR/PMUs placement and PMU replacement plan for up to _____ (XX) ___ kV and ___ kV substations, plus external synchrophasor data exchange with other entities for up to _____ (XX) similar substations? (Yes/No)

7. Does the vendor provide reliable data acquisition and archiving for off-line engineering applications such as:

    a. Post-disturbance analysis, such as NYISO's Power System Analysis (PSA) or other similar ones with at minimum PSA's current functionalities (trending for active and reactive power; magnitude and phase angle of V and I phasor measurement; phasor vector diagram display; low frequency oscillation analysis, etc.) (Yes/No)
    b. Play back and forward simulation? (Yes/No)
    c. Modal or oscillatory analysis? (Yes/No)
    d. System model validation? (Yes/No)

8. Does the vendor have a reliable data acquisition and buffering capability for real-time situation awareness applications, meeting the overall speed requirement, preliminarily set at the **one second** latency maximum? (Yes/No)

9. Can the three basic functionalities for all real-time situation awareness applications be provided?

    a. Alarm and warning? (Yes/No)
    b. Trending? (Yes/No)
    c. Compliance logging and reporting? (Yes/No)

10. Does the vendor's application include the following real-time situation awareness applications (optional applications may be deployed later depend upon availability, costs, and benefits)?

    a. Voltage phase angle monitoring? (Yes/No)
    b. Voltage stability monitoring? (Yes/No)
    c. Low frequency oscillation monitoring? (Yes/No)
    d. Fault location? (Yes/No)
    e. Island identification (optional)? (Yes/No)
    f. Island condition monitoring (optional)? (Yes/No)
    g. Small-Signal Stability Monitoring (optional)? (Yes/No)

h. Real-time thermal line rating monitoring (optional)? (Yes/No)
i. Distributed Generation (DG)/Independent Power Producer (IPP) Applications (optional)? (Yes/No)

11. Does the system support data exchange with various ISO entities (MISO, PJM-ISO, Reliability Coordination Councils, and Transmission and/or Generator owners)? (Yes/No)

12. ISO entities shall be able to request and retrieve real-time data stream with data reporting rate and data types that may be different from that used by NYISO SGI. (Yes/No)

13. NYISO SGI shall be able to request and retrieve real-time data stream with data reporting rate and data types required by NYISO SGI. (Yes/No)

14. Are the vendor's applications capable of interoperability of PMUs and DFR/PMUs from different suppliers with IEEE C37.118-2005 level 1 steady-state performance requirements? (Yes/No)

15. Can the DFR/PMU Units communicate with the PDAC or Data Management Subsystem via both UDP/IP and TCP/IP protocols through an IP-based network (both IPv4 and IPv6 shall be supported)? (Yes/No)

16. The destination IP address of DFR/PMU when using UDP/IP protocol shall be user configurable and shall include multicast address space. (Yes/No)

17. PDAC shall be able to support multiple data and messaging protocols, such as IEEE C37.118-2005 data frame protocol, ICCP, IEC 61850 (UCA-GOOSE messaging) standards, DNP 3.0, and OPC. (Yes/No)

18. Can the system recover lost data if errors occur in telecommunication channels (this could be achieved in part by pushing the data to both primary and backup PDACs, but primarily through DFR/PMU local data storage and lost data retrieval through PDAC ←→ PDC or DFR/PMU interactions)? (Yes/No)

19. Is the received data in the PDAC available for analysis by computer programs executed on the PDAC Application Server and also accessible through NYISO internal network for remote analysis? (Yes/ No)

20. Does the system ensure data filing, backup and restoration after hardware or software failure? (Yes/No)

21. What is the maximum Phasor data latency for Visualization?

22. Can the system handle a minimum of 30 days online full data storage for all received PMU data at PDAC and other data at CCS? (Yes/No)

23. Can the vendor's system provide a minimum of five (5) year's event storage for long-term event archive? (Yes/No)

24. Can the SGI data be enabled to use multiple vendor application software (visualization, advanced network applications, voltage support equipment monitoring and control, fault locator….etc)? (Yes/No)

25. Can the communication between PDAC and EMS/SCADA (Supervisory Control and Data Acquisition) system be through ICCP protocol? (Yes/No)

26. Can the system allow for communication channel interruption of up to 1 hour for long-term system dynamics recording? (Yes/No)

27. Can the vendor's system accommodate the following:

    a. The system shall be able to accommodate PMU devices reporting rate up to 60 samples per second. (Yes/No)
    b. The system shall allow manual and automatic global triggering of DFR data recording (Yes/No)
    c. The CCS shall be able to retrieve and store recorded PMU data from DFR/PMU (Yes/No)
    d. The CCS shall be able to retrieve and store recorded DFR data (typical total recording length 10 to 1200 seconds) from DFR/PMU (Yes/No)
    e. DFRs record at a sample rate of 100 to 120 samples per second (Yes/No)
    f. Pre-fault time 2 to 600 seconds (Yes/No)
    g. Post-fault time 4 to 300 seconds (Yes/No)
    h. Recording time after end of triggers 2 to 120 seconds (Yes/No)
    i. The system shall be "secure by default" with all security features enabled in the standard installation configuration. (Yes/No)

28. Does the system support a minimum security feature set, including:

    a. Remote configuration via secure protocol per [reference]? (Yes/No)
    b. Account management per [reference]? (Yes/No)
    c. Authentication per [reference]? (Yes/No)
    d. Authorization per [reference]? (Yes/No)
    e. Auditing per [reference]? (Yes/No)
    f. All relevant NYISO Information Technology Security (ITS) policies and standards per [references]? (Yes/No)

A.5 SGI System Requirements for Future Expansion/Integration

It may not be possible to list all system requirements for SGI future expansion/integration. A few anticipated requirements are summarized as follows. The vendors are requested to provide a Yes/No answer to the following functionalities.

1. Capable of supporting future PMUs and DFR/PMUs deployment in up to 500 NYISO substations and data exchange with up to 500 external substations (Yes/No)

2. PMUs and DFR/PMU shall be able to support multiple data and messaging protocols, such as updated IEEE C37.118 data frame protocol, IEC 61850 (UCA-GOOSE messaging) standards, DNP 3.0, and OPC, and possibly other protocols for interaction/integration with other devices/systems. (Yes/No)

3. PDAC shall be able to support multiple data and messaging protocols for interacting with various monitoring, protection, and control IEDs. (Yes/No)

4. SGI shall be able to support multiple data and messaging protocols for interacting with other NYISO systems. (Yes/No)

5. The system shall be able to support high speed (tens of milliseconds) and highly reliable (no interruption under any signal point failure) messaging and intra-/inter-data exchange for protection and control applications. (Yes/No)

Appendix B – Equipment

1. General info about your company's PMU product offerings (off-the-shelf products and ones under development, supplying info – lead time, etc.)

2. Specific info for each PMU product that your company offers (type of the device, standards supported, standards compliance, HW/SW functions and capabilities, device specifications, etc.)

3. General info about your company's substation PDC product offerings (off-the-shelf products and ones under development, supplying info – lead time, etc.)

4. Specific info for each substation PDC product that your company offers (type of the device, standards supported, standards compliance, HW/SW capabilities, device specifications, etc.)

5. General info about your company's control center PDC product offerings (off-the-shelf products and ones under development, supplying info – e.g. lead time, etc.)

6. Specific info for each control center PDC product that your company offers (type of the device, standards supported, standards compliance, HW/SW capabilities, device specifications, etc.)

B.1 Digital Fault Recorder (DFR) Function

The DFR function is one of the two main functions of the combined DFR/PMU devices NYISO plans to install. Vendor's response should state whether or not they can supply the devices with the following minimum functionalities.

1. The DFR function should be able to record data simultaneously in three time domains: high-speed transient fault (minimum 7860 samples/second up to 60 seconds), low speed long-term dynamic swing (760 samples/second for up to 16 minutes), and continuous trend (as per NERC PRC-002-RFC-1 at 30 samples/second for up to 30 days). (Yes/ No)

2. The digital fault recorder function should have the capability of sending output files in COMTRADE format, and either manually or automatically uploading output files to the PDAC. Information on the COMTRADE format is available in IEEE C37.111-1999, "IEEE Standard for Common Format for Transient Data Exchange (COMTRADE) for Power Systems" or its successor standard. (Yes/No)

3. Data files are to be named in conformance with IEEE C37.232 "Recommended Practice for Naming Time Sequence Data Files". (Yes/No)

4. Wide varieties of triggers should be available to initiate transient and long-term recordings such as faults, manual and automatic requests. (Yes/No)

5. Fault and event recording data should be sent either automatically from the DFR/PMU Units to the System and Data Management (SDM) servers upon the occurrence of any local or globally triggered event, or upon request and it will be stored in the SGI Real-time and Historian database after data validation. (Yes/No)

6. DFR should interface with external PMU/DFRS and PDCs and eventually Data Management. (Yes/No)

Vendor's system should conform to the input, output and services specified below:

7. DFR Input

    a. Triggers received from other DFR/PMUs, and/or Global Event Record Trigger Management Applications (Yes/No)

    b. Requests to send recorded data to SDM servers (Yes/No)

    c. NYISO Phasor Gateway (Future) (Yes/No)

8. DFR Output

    a. Recorded data to SDM servers (Yes/No)

    b. NYISO Phasor Gateway (Future) (Yes/No)

9. DFR Services

    a. Transient and long-term events can be acquired by any triggered event when one of the user programmable trigger thresholds is exceeded. The available triggers must include:

    b. Over magnitude (Yes/No)

    c. Under magnitude (Yes/No)

    d. Absolute Angle (Local vs. Remote) (Yes/No)

    e. Absolute frequency deviation from 60 Hz (Yes/No)

    f. Rate of change of frequency (Yes/No)

    g. Digital change of state (Yes/No)

    h. Linear combination of magnitude, frequency and rate of change of frequency (Yes/No)

    i. Manual (local and remote) (Yes/No)

j. Cross-trig by neighboring units (Yes/No)

k. Global trig by Global Event Trigger management application (Yes/No)

B.2 Phasor Measurement Unit (PMU) Function

B.2.1 General PMU Requirements

The PMU functions should have, at a minimum, the following capabilities.

1. The PMU function of NYISO DFR/PMU must be able to record electrical disturbances in phasor format and provide continuously streamed phasor measurement data to phasor data concentrators at GCC or other locations. (Yes/No)

2. Through the use of a GPS clock, the PMU function must be able to generate phasor measurement data synchronized with UTC from installed locations throughout the power system. (Yes/No)

3. A PMU, whether it is a standalone or an integrated unit, typically must have a number of analog and digital channels. The number of available analog and digital channels can vary. Analog channels can be utilized to record real-time information and can be configured as either a voltage phasor or a current phasor. Vendors are required to specify how many analog and digital channels the PMU will support. (Yes/No)

4. Synchrophasor data should be continuously streamed from the PMUs to the PDAC (at a typical rate of 30/60 frames per second). The streamed synchrophasor data will be pushed to PDAC and SDM for validation and will be stored in Real-Time and Historian SGI databases. (Yes/No)

5. The information captured by the NYISO DFR/PMUs store rows of positive sequence phasor data. As a real-time phasor measurement instrument, some PMUs may be expected to both transmit and/or receive phasor data to/from remote locations. (Yes/No)

6. The PM function must be able to compute the positive sequence voltage and current phasors at precisely the moment synchronized with UTC. (Yes/No)

7. The computed data can be transmitted on a very high speed communication channel to a central location where a “Phasor Data Concentrator (PDC)” collects the data from all the PMUs and redistributes the time-aligned data. (Yes/No)

8. To ensure the continuity and reliability of receiving PMU data stream, each PMU streamed data must be sent to two locations, via two different communication channels. (Yes/No)

PMU Input

9. PM functions should, at a minimum, be able to receive voltages and currents for 3 phases from a number of PTs and CTs and breaker status bits through digital words. (Yes/No)

10. As a real-time phasor measurement instrument, the PMU should be able to both, transmit and/or receive phasor data to/from remote locations for comparison with local phasors. (Yes/No)

PMU Output

11. PMU computes the positive sequence voltage and current phasors. The computed data is then transmitted on a very high speed communication channel to a "Master Station (MS) Phasor Data Concentrator" labeled as the PDAC at a central location.

12. Many current PMUs use the Macrodyne format, but the majority uses the IEEE C37.118 format. Current PMUs measure ten or fewer phasors, and up to two digitals.

13. Vendors must conform to the following criteria for maximum PMU output data rate calculation using IEEE C37.118-2005:

    a. All data will be in floating-point format (Yes/No)

    b. Ten phasors and two digital words will be transmitted (Yes/No)

    c. Data transmission rate at 30 or 60 samples per second (Yes/No)

14. Estimation of bandwidth requirement for an assumed DFR/PMU:

    a. 18 bytes HDR, SOC, FRACSEC, PMU_ID, CRC (Yes/No)

    b. 8 bytes overhead (Yes/No)

    c. 8 bytes STAT (Yes/No)

    d. 80 bytes phasors (PMU with 10 phasors) (Yes/No)

    e. 4 bytes FREQ, DFDQ (Yes/No)

    f. 4 bytes DIG (Yes/No)

    g. 122 bytes Message total (Yes/No)

    h. 122 bytes/msg X 30 msg/sec = 3660 bytes/sec (Yes/No)

    i. 3660 bytes/sec X 8 bits/byte = 29,280 bits/sec (bps) actual data rate (Yes/No)

(Needs recalculation per NYISO input)

    j. Provision should be made for each PMU having:

1. a maximum of 20 phasor outputs at 60 samples per second (Yes/No)
2. a maximum of 30 to 40 digital outputs at 60 samples per second (Yes/No)

k. Communication provision at each substation shall also consider the total number of DFR/PMU installed in the substation if these DFR/PMUs will share the same communication path.

B.2.2 PMU Specific Questions

15. Off-the-shelf PMU product offerings – please list all models that have been released to the market
16. Planned PMU product offerings – please list all models that planned to be released to the market within the life of the project equipment.
17. Sales and technical support info
18. Field implementation support
19. Response time to product problems

For each PMU product model, please provide the following specific information/materials, if available.

20. A summary description of the product
21. Product specification
22. User manual
23. Initial release date of the product
24. Number of units sold
25. Type/certification test reports
26. Lead time for ordering
27. Spare parts and replacement support
28. Warranty period

For each PMU product, please answer the following specific questions (provide additional details to each answer)

For both standalone PMUs and integrated PMU (Relay/PMU, DFR/PMU, etc.):

29. Is the device capable of measuring positive sequence phasors from three-phase inputs?

30. Is the device capable of producing positive sequence phasors from single-phase input?
31. Is the device capable of measuring single-phase phasors for each phase of three-phase inputs?
32. Does the device provide internal compensations for VT/PT errors?
33. Does the device provide internal compensation for CT errors?
34. Does phasor measurement support all reporting rates of C37.118-2005?
35. Does phasor measurement support reporting rate of 60 frames/s?
36. Does phasor measurement support reporting rate of 120 frames/s?
37. Does phasor measurement performance at 10, 12, 15, 20, and 30 frames/s meet level 1 requirements of C37.118-2005?
38. Does phasor measurement performance at 10, 12, 15, 20, 30 and 60 frames/s meet class P and M requirements of the current draft C37.118 (will be C37.118.1) standard?
39. Does phasor measurement performance at 120 frames/s meet class P and M requirements of the current draft C37.118 (will be C37.118.1) standard by adjusting the requirements to 120 frames/s?
40. Has it implemented all messaging frames defined in C37.118-2005?
41. Are all time quality related flags defined in C37.118-2005 supported?
42. Does the device use an internal GPS receiver?
43. Does the device support IEEE 1588?
44. Does the device use external timing source?
45. If external timing source is used, will the device be able to determine if the timing source is synchronized to UTC?
46. If IEEE 1588 is supported, will the device be able to determine if the master clock is synchronized to UTC?
47. When the synchronization to UTC is lost, will the device be able to positively determine the timing accuracy of its internal clock to UTC?
48. Does the device provide at least two Ethernet ports?

49. Does the device provide options for using either galvanic or optical Ethernet port connector?
50. Does the device support both IPv4 and IPv6 for phasor data communication?
51. Does the device support using both TCP/IP and UDP/IP for phasor data and messaging communication?
52. Can the device be configured for sending phasor data using UDP/IP and other messaging using TCP/IP?
53. Does the device support sending phasor data to either unicast or multicast IP address?
54. Can user configure the multicast IP address to be used?
55. Does the device include a feature to send multiple phasor data frames in one IP packet?
56. If the device include a feature to send multiple phasor data frames in one IP packet, can user configure how many frames to be included?
57. Does the device support OPC protocols? If yes, how it is implemented and used?
58. Does the device support 61850 protocols? If yes, how it is implemented and used? Which specific parts of the standard are supported?
59. Does the device support DNP protocols? If yes, how it is implemented and used?
60. Does the device support any other data and messaging protocols? If yes, please explain each of them.
61. Does the device support/generate more than one phasor data stream?
62. If supporting more than one data stream, can each data stream be configured independently by user?
63. Does the PMU provide any internal data storage for phasor measurement data?
64. Has the device been tested to meet all electrical, electromagnetic compatibility, environmental standards for substation equipment? If it has, please provide test report/certification for each test.
65. Does the device support the use of all types of substation DC supply voltages in US?
66. Does the device provide a minimum of 200 ms power failure bridging time without an internal battery?

67. Does the device provide a minimum of 10 minutes power failure bridging time with an internal battery?

68. Does the device allow users to fully comply with NERC CIP requirements when connected to the PMU system network?

For integrated PMUs

69. Does PMU function share the same input circuits and analog filters with other functions?

70. Does PMU function share the same binary input/output connectors with other functions?

71. Does the PMU function share the same Ethernet communication ports with other functions?

72. Can PMU function and other functions be configured independently?

73. Can the PMU function be configured without stopping the operation of other functions?

74. Can other functions be configured without stopping PMU function?

75. Can the device be configured as a standalone PMU device?

76. Has the device been tested to confirm that normal PMU function will not be affected under the peak operation of other functions? If yes, please provide a detailed description about how the device was configured, how the test was performed, and the recorded results.

B.3 Phasor Data Concentrator (PDC) Function

B.3.1 PDC Specific Questions

1. Off-the-shelf Control Center PDC product offerings – please list all models that have been released to the market

2. Planned Control Center PDC product offerings – please list all models that planned to be released to the market within one year

3. Sales and technical support info

4. Field implementation support

5. Response time to product problems

6. For each Control Center PDC product model, please provide the following specific information/materials if available

7. A summary description of the product
8. Product specification
9. User manual
10. Initial release date of the product
11. Number of units sold
12. Type/certification test reports
13. Lead time for ordering
14. Spare parts and replacement support
15. Warranty period

For each Control Center PDC product, please answer the following specific questions (Provide additional details to each answer as needed for your offering to be understood.)

B.3.2 Type of Control Center PDC

16. Is this a phasor data concentration only product, meaning that it only handles phasor measurement data from various PMUs/PDCs (substation PDCs, other control center PDCs, etc.)?
17. Is this a general data concentration type of product, meaning it may also handle different types of data other than the phasor measurement data from various PMUs in a substation/PDCs? The other types of data could include such data as DFR data, relay data, remote terminal unit data, and so on.
18. Is this an all inclusive WAMS or WAMPAC system offering that includes the phasor data concentration, data management, system management, WAM/WAC/WAP applications, visualizations, and so on? If yes, please provide detailed description of the system.
19. Is this a software only product, meaning that it can run on any off-the-shelf standardized hardware and operating systems that meet its specifications?
20. If it is a software only product, can it run on a MS Windows server system?
21. If it is a software only product, can it run on a Linux server system?
22. If it is a software only product, can it run on other types of server systems, such as server clusters, cloud-computing environment, etc.? Please list all other supported server systems.

23. If it is not a software only product, can the specialized hardware be supplied by more than one supplier?

24. Does the product support system redundancy design similar to that of a production grade EMS/SCADA system? If yes, please provide a detailed description how the product can be used in a redundant system design.

B.3.3 Communication/Networking Capability

25. Does the product support at least two four Ethernet ports for data input and output?

26. If using specialized hardware, does the product support both optical and galvanic connectors for its Ethernet ports?

27. If using specialized hardware, does the product support at least 1000Mbps?

28. If using specialized hardware, does the product support both IPv4 and IPv6?

29. Does the product have an accurate system clock that is synced to be within 1 uS to UTC? If yes, please describe how this is achieved (e.g., GPS, IEEE 1588) and list the use of the system clock in various functions and applications of the product. If using specialized hardware, does the product also support other data communication methods, such as serial data ports?

B.3.4 Data Input Capabilities

30. Does the product support receiving phasor data in IEEE C37.118-2005 data frame protocol?

31. Does the product support receiving phasor data in other data protocols, such as proprietary data protocols, IEC 61850, IEEE 1344, etc.? If yes, please describe each of the data protocol supported.

32. Does the product support receiving phasor data in either TCP/IP and or UDP/IP data packets?

33. If the product supports receiving data in UDP/IP packets, does the product support receiving phasor data sent by PMUs/PDCs in either a unicast IP address or a multicast IP address? If yes, please describe how receiving multicast UDP/IP data is accomplished.

34. If the product is a general data concentrator, does the product use other protocols to receive phasor/non-phasor data in addition to phasor data protocols C37.118/61850?

35. Is there a limit on how many real-time phasor data streams that the product can receive from PMUs?

36. Is there a limit on the highest receiving phasor data rate (30, 60, 120 or higher) that the product can support?

37. Are the above two limits affected by the size of data packet of the phasor data streams that it receives from PMUs?

38. Does the product have to be stopped for updating PMU/PDC configuration changes? If not, please describe how the product updates PMU/PDC configuration changes without stopping its continued operation for TCP/IP data streaming, and for UDP/IP data streaming (both unicast and multicast).

39. Does the product provide a PMU/PDC data stream start/stop function to start or stop a data stream from a PMU or PDC? If yes, please describe how this function is implemented for TCP/IP data streaming, and UDP/IP data streaming (both unicast and multicast) and the messaging protocol used.

B.3.5 Data Preprocessing Capabilities

40. Does the product include certain data processing functions in addition to time-alignment of received data streams, such as data validation, data error detection, down sampling, filtering, etc.? If yes, please list all data processing functions and their specifications.

41. Are all processing functions for real-time data streams performed periodically according to fixed time schedules that are synced to UTC?

42. Can the time-alignment function of your product create output data streams that maintain original PMU/PDC data frame configurations?

43. Can the time-alignment function of your product create new PMU data configurations in the output data stream that are different from original PMU/PDC data frame configurations?

44. Does the time-alignment function provide a user configurable waiting time setting (used for waiting input data packets with the same time tag to arrive before the time alignment to start)?

45. Will the input data packets that arrived after the waiting time be discarded?

46. Does your product provide a pack-and-go function (i.e., multiple input PMU data packets are only packed into one IP packet and send out without any time-alignment or other data processing performed)?

47. Does the down-sampling function (changing phasor data rate from a high one to a lower one, e.g. from 60 fps to 30 fps) of your product use the simple skip-the-point method?

48. Does the down-sampling function of your product involve filtering? If yes, please describe how the down-sampling is accomplished.

49. Does the product perform certain data validation for received data? If yes, describe what types of validations are performed and how they are performed.

50. Does the product include a data error handling function? If yes, please describe what types of data errors that it handles, and how these errors are handled.

51. Does the product include a QoS (latency, interruptions, etc.) monitoring function for received data streams? If yes, please describe how this function works.

B.3.6 Data Storage and Retrieval Capabilities

52. Does the product include a data storage and retrieval function? If yes, please describe how the function is implemented (hardware and software). To be completed

53. Does data storage support both online data storage for fast retrieval and long-term data storage and archive (e.g., historian)?

54. Is the data storage capacity expandable so that there will be no limit on the amount of data stored?

55. Is the product using an open data format for storing and retrieving the data? If yes, please identify the format. If not, please describe the format used.

56. Does the product provide data retrieval methods for remote retrieval of the stored data? If yes, please describe each method and the associated data retrieval API and protocols.

57. Does the storage function only handle synchrophasor data storage and retrieval? If other data are also handled, please identify types of data that it also handles and how they are handled.

B.3.7 Data Management Capabilities

58. Does the product perform certain data validation for received data? If yes, describe what types of validations are performed and how they are performed.

59. Does the product include a data error handling function? If yes, please describe what types of data errors that it handles, and how these errors are handled.

60. Does the product include a QoS (latency, interruptions, etc.) monitoring function for received data streams? If yes, please describe how this function works.

61. Does the product provide a missing data retrieval function to retrieval missing data from substation PDCs or other PDCs that have their own data storage capability?

62. Does the product provide a late data handling function? If yes, please describe how late arrival data is handled (e.g., discarded, or stored with an arrival time tag, etc.).

B.3.8 System Management Capabilities

63. Does the product provide system management functions for device management, applications management, and so on?

64. Does the product manage the device and applications registration and configuration? If yes, please describe how these are managed.

65. Does the product keep logs on the device and applications registration and configuration changes?

66. Does the product system management function manage the start and stop of applications?

67. Does the product include system resource management functions?

68. Does the product provide security services for system access control?

69. Does the product provide system status monitoring, mitigation and alarming functions?

B.3.9 Applications Included

70. Does the product include any supporting system applications, such as data visualization, simple manipulation of stored data, etc.? If yes, please describe each of them. To be completed

71. Does the product include any alarm functions? If yes, describe what types of alarm functions are included, how each function works, and the purpose of each alarm function.

72. Does the product include any substation monitoring, protection and control functions, such as substation state estimator, substation backup protection, etc.? If yes, please describe each application function.

73. Are all supporting system applications, alarm functions, and/or substation monitoring, protection and control functions running on the same processing unit as the data

concentration functions? If not, please describe how these are running on different processing units and how they interface with each other.

B.3.10 Data Output Capabilities

74. Does the product support sending streaming phasor data in IEEE C37.118-2005 data frame protocol?

75. Does the product support sending streaming phasor data in other data protocols, such as proprietary data protocols, IEC 61850, IEEE 1344, OPC, DNP, etc.?

76. Does the product support sending phasor data in either TCP/IP and or UDP/IP data packets?

77. If support sending data in UDP/IP packets, does the product support sending phasor data in either an unicast IP address or a multicast IP address?

78. If support sending data in UDP/IP packets, does the product allow users to configure the destination IP address, be it a unicast or a multicast IP address?

79. Is the product support generating and sending multiple phasor data streams that are different from each other (data rate, number of measurement data included, etc.)?

80. Can each output phasor data stream be configured independently for amount of data to be included, the reporting data rate to be used, and so on?

81. Does the product have a function to pack several data frames of an output data stream into one IP data packet?

82. If the product has a function to pack several data frames of a data stream into one IP data packet, does the product allow users to configure how many data frames in a phasor data stream (e.g., an IEEE C37.118-2005 data stream) that can be sent in one IP data packet?

83. Can the product create output data streams that maintain original PMU/PDC data frame configurations from each PMU/PDC device? If yes, please describe how this is accomplished and the data protocol used.

84. Can the product create output data streams that do not maintain the same PMU/PDC data frame configurations of each PMU/PDC device? If yes, please describe how this is accomplished and the data protocol used.

85. If the product is a general data concentrator, does the product use any other protocols to receive output phasor/non-phasor data in addition to phasor data protocols C37.118/61850?

86. Is there a limit on how many real-time phasor data streams that the product can output?

87. Is there a limit on the highest output phasor data rate (30, 60, 120 or higher) that the product can support?

88. Are the above two limits affected by the size of data packet of the phasor data streams that it outputs?

B.3.11 System Capacity

89. Is the system expandable such that there are no limits on number of input/output real-time phasor data streams, the highest input/output phasor data rates, the size of input/output data packet size, and the number of processing functions that the product can support? If not, please indicate what could be your product's limits.

90. Has the product's system capacity been verified by appropriate tests? If yes, please provide the information on the performed test and the test results.

B.4 PMN Data Processing, Data Management, and Applications

B.4.1 Phasor Data Acquisition and Control (PDAC)

Will the PDAC deployed for SGI support the following data protocols:

1. Data Input Format IEEE C37.118-2005 (Yes/No)
2. Data Output Format IEEE C37.118-2005 (Yes/No)
3. IEC 61850

PDAC Input

4. It reads the time-tag on incoming PDC and PMU phasor data and places the data in an internal circular buffer functionally. The PDC shall have a circular buffer with sufficient length for time alignment of received PDC and/or PMU real-time data stream. In synthesis, the PDC correlates phasor data by time tag to create a system-wide measurement set. (Yes/No)

5. PDAC shall be fully configurable and redundant. The system parameters are, but not limited to, overall system parameters such as data rate, size of data table, number of CPU boards, number of PDCs, and number of PMUs. (Yes/No)

6. The inputs from PDCs and external PDCs to PDAC must also be fully configurable. These inputs are, but not limited to, number of phasors, number of digital status words, reporting rates, number of status bytes, and format data. (Yes/No)

PDAC Output

7. PDAC shall multicast correlated PMUs and other PDCs data to a specific port over a specific subnet to be readable to all subsystems on that subnet. (Yes/No)

8. Time-aligned phasor data from all PMUs shall be streamed out at the same rate (30 frames per second) to NYISO GCC's SGI LAN where SGI Real-Time database, Visualization servers (VSs), and Historians are connected. (Yes/No)

9. Received DFR data must able to be sent to NYISO GCC's SGI LAN where SGI Real-Time database, VSs, DFR data analysis application servers, and DFR data Historians are connected. (Yes/No)

PDAC Services

Does PDAC provide the following services:

10. Receive and process data from an initial 160 PMUs (80 NYISOs own DFR/PMUs plus 80 equivalent external PMUs through external PDCs), with an estimate of over 1,000 PMUs by 2020 (500 NYISO's own DFR/PMU and PMUs, and 500 external standalone and integrated PMUs), each PMU pushes data out at a maximum rate of 24,480 bits/sec. (Yes/No)

11. Receive and process data from multiple ISO PDCs (between 10 to 20 PDCs) for an initial equivalent external 80 PMUs. (Yes/No)

12. Time-align the PMUs and PDCs data from all inputs and stream out the time-align phasor data on the CC's SGI LAN using the UDP/IP protocol. To minimize latency, this packet is sent out as soon as all data for a given time-tag has been received or a preset time limit is reached. (Yes/No)

Additional capabilities supplied include:

13. Store time-aligned data in SGI Real-Time Database for applications to use. (Yes/No)

14. Save streamed data in SGI Historian as requested. (Yes/No)

15. Disturbance monitor to record a table of data on the PDC disc whenever a power system disturbance is detected by a PDC or PMU. (Yes/No)

16. In response to a request from the EMS, the service must read the most recent phasor measurements from the data buffer, calculate various data quantities, such as bus voltage magnitude and relative phase angle between stations, and system frequency to send back to the EMS.

17. Per PMU event capturing trigger, create binary files at a configurable location. Each file will capture the one-minute data contained in the circular buffer at the time of trigger (pre-trigger data) and up to four minutes (or more) of post-trigger data. This data will be sent to the Data Management subsystem.

B.4.2 System Management (SM)

The main task of SM is providing overall equipment functionality within SGI. It is expected that the Control Center PDC SM will be integrated with the SGI System Management functions. Then EMS SM will be coordinated with the PMN components and subsystems.

An important function of the SM is to provide system administration functions, such as PDAC/PDC/DFR/PMU registration, external PDC registration, application registration, and so on. This will allow SGI to provide system configuration services and security services. The minimum input, output and service requirements must be provided.

SM Input

18. PDC configuration (Yes/No)
19. DFR/PMUs configuration (Yes/No)
20. Applications data output (TBD) (Yes/No)
21. External data Proxy servers (Yes/No)
22. Real-Time Data needed by application (Yes/No)
23. Grid network data from EMS server (Yes/No)
24. EMS/PDAC Historian output (Yes/No)

SM Output

25. Validated and quality checked PDC/DFR/PMU configuration (Yes/No)
26. Validated and quality checked external proxy configuration (Yes/No)
27. Pass-through EMS data (Yes/No)
28. Pass-through application outputs (Yes/No)

SM Services

Data Base Delivery via GCC SGI LAN

29. Delivers data requested by Applications (Yes/No)

30. Delivers data requested by Visualization (IEEE C37.118 format) (Yes/No)

31. DFR data recording triggers (Yes/No)

32. SCADA/EMS Interface via GCC SCADA/EMS and SGI LAN (Yes/No)

33. Maps PMU measurements to the SCADA points and network model devices (gens, loads, branches, etc.) (Yes/No)

34. Map of PMU measurements in SCADA database for State Estimator (SE) use at a sample rate of one sample per second (Yes/No)

B.4.3 Data Management (DM)

The main task of the Data Management is providing data retrieval, data validation, data storage and data delivery services within SGI, not only for the existing EMS but also for all of the added PMN subsystems.

DM Input

35. Time-aligned PMU data from PDAC in IEEE C37.118-2005 format (Yes/No)

36. DFR data from DFR/PMUs in COMTRADE format (Yes/No)

37. Applications data output (TBD) (Yes/No)

38. External data Proxy server outputs (earthquake, fire, traffic and weather) (Yes/No)

39. Real-Time Data requested by applications (Yes/No)

40. Grid network data for EMS (Yes/No)

41. EMS/Historian output (Yes/No)

DM Output

42. Validated and quality checked time-aligned PMU data stream in IEEE C37.118-2005 format (Yes/No)

43. Validated and quality checked external proxy data (Yes/No)

44. Pass-through EMS data (Yes/No)

45. Pass-through application output data (Yes/No)

DM Services

Data Retrieval via GCC SGI LAN and SGI WAN:

46. Retrieves and validates PMUs synchrophasor data from PDAC (Yes/No)
47. Retrieves and validates fault and event recording data from DFRs (unless there are PDCs commercially available) (Yes/No)
48. Retrieves external Proxy data (earthquake, fire, traffic and weather) (Yes/No)
49. Data Storage via GCC SGI LAN (Yes/No)
50. Stores DFRs recorded data in SGI Historian database (COMTRADR format) (Yes/No)
51. Stores PMUs synchrophasor data in SGI RT database (IEEE C37.118 format) (Yes/No)
52. Stores external Proxy data (earthquake, fire, traffic and weather) (Yes/No)
53. Delivers data requested by Applications (application defined API format) (Yes/No)
54. Delivers data requested by Visualization (IEEE C37.118 format) (Yes/No)
55. DFR data recording trigger (Yes/No)
56. Initiates DFRs area or global recording requests requested by application (Yes/No)
57. EMS Interface via GCC EMS and SGI LAN (Yes/No)
58. Maps PMU measurements to the SCADA points and network model devices (gens, loads, branches, etc.) (Yes/No)
59. Puts PMU measurements in SCADA database for State Estimator (SE) use at a sample rate of one sample per second (Yes/No)
60. Retrieves SE solution from EMS application database/server every minute to update visualization displays (Yes/No)
61. Retrieves SCADA values from SCADA database/server for visualization displays (Yes/No)
62. Validating PMU measurements vs SCADA values when available (Yes/No)
63. Transferring requested PMU and DFR data to engineering database by request (IEEE C37.118 and COMTRADE format) (Yes/No)

B.4.4 Application Management Services (AMS)

The main task of Application Management Services is to run SGI analytical, engineering, and other applications. The added PMN applications are expected to be integrated with the existing

EMS application management services function. Following is a summary of application server functions:

AMS Input

64. Validated streaming PMU/EPDC data (Yes/No)
65. Validated PMU/EPDC data from SGI Real-Time database (Yes/No)
66. PDAC streamed PMU data – not validated by SDM (Yes/No)
67. DFRs data from SGI Real-Time database (Yes/No)
68. Grid digital and analog data from EMS database (Yes/No)
69. Grid network solution data from SGI Real-Time database (Yes/No)
70. External non-electrical data from SGI Real-Time database (Yes/No)
71. Application output data from SGI Real-Time database (Yes/No)

AMS Output

72. Alarms and violations to be reflected in visualization (Yes/No)
73. MW and MW flows and losses (Yes/No)
74. Compliance Reports (Yes/No)
75. Performance Reports (Yes/No)

AMS Services

76. MW and Mvar flow calculations (Yes/No)
77. MW and Mvar loss calculation (Yes/No)
78. Line thermal monitoring (Yes/No)
79. PMU measurement versus SCADA data validation (Yes/No)

Generating multi-level/category Alarms & Warnings based on:

80. Monitored Voltage Phase Angle differences between two points and/or any points to the reference point (Yes/No)
81. Low voltage detection (Yes/No)
82. Measurements rate of change detection (Yes/No)

83. Low frequency oscillation detection (Yes/No)

84. Branch thermal limit violation (Yes/No)

85. Branch flow violation (Yes/No)

86. Phase angle and frequency deviation (Yes/No)

87. Island detection (Yes/No)

88. PMU measurement versus SCADA data validation (Yes/No)

89. Compliance Report Generation (Yes/No)

90. DFR recording initiation for selected areas or global (Yes/No)

91. Network model validation (Yes/No)

92. Creating the stream files for post-disturbance analysis (dst Format?) (Yes/No)

93. Replaying or playing back previous recorded stream files in dst format. The play back option must allow for a review of a specific time-frame where an event happened (Yes/No)

94. Produce meaningful plots, tables, charts and analysis of power transmission system conditions (Yes/No)

95. The capability to select which quantities to show must be provided (Yes/No)

96. The length of the plots must be selectable (Yes/No)

97. The program could be set to continuously record data on disc over a number of hours, limited by disc space (Yes/No)

98. Flow Gates and Interface Monitoring (Yes/No)

99. Automated daily or weekly report generation with emailing capability providing summary information on. (Yes/ No)

100. PMU/PDC performance overall summary and by individual PMUs (Yes/No)

101. Number of alarms by alarming category (criteria) and region (Yes/No)

102. Frequency trends and statistics (max, min, average and specific patterns) (Yes/No)

103. Angle difference – Max, min, and average between regions during peak and off-peak times (Yes/No)

104. Zonal voltage patterns at key facilities (Yes/No)

105. Relative angle trends at key facilities (Yes/No)

B.4.5 Visualization Management Services (VMS)

Visualization management services will support a full-graphical operational visualization environment for centralized and systematic real-time wide-area system monitoring and information presentation and multi-layer display of synchrophasor data from applications and data management subsystems. The vendor should confirm if the visualization subsystem satisfies the minimum requirements listed below.

106. Multi-view graphical information display (Yes/No)

107. One main view for system-wide information visualization and presentation (Yes/No)

108. Multiple sub-views for both system-wide and detailed information visualization and presentation (Yes/No)

109. Multi-layer information visualization and presentation capability with role-based authentication and authorization (Yes/No)

110. Main view shall have a geographic layer as its base layer to allow the integrated information visualization and presentation of PMU data/alarms/calculations with imported, SCADA, EMS, real-time fire, traffic, weather, earthquake, lightning indicator data, and system one-line diagrams in other overlay layers (Yes/No)

111. Ability to bring in and display information from any real-time application (i.e., FNET) (Yes/No)

112. Dynamic updates with status changes, such as dynamic line coloring, islanding, etc. (Yes/No)

113. Trending capability (Yes/No)

114. Pan and zoom capability (Yes/No)

115. Tabular displays with real-time updates of synchrophasor data (Yes/No)

116. Ability to distinguish the data in the displays by the data sources (historical data from archive; calculated values; originated PDC, PMU, device signal, etc.) (Yes/No)

117. Ability to serve displays in remote user stations via the Internet (Yes/No)

118. User report definition capability (Yes/No)

119. Selective alarm parameter for individual PMUs (Yes/No)

120. Alarm filtering, grouping and alarm report generation capability (Yes/No)

121. Pop-up or flash feature on receipt of a significant alarm (Yes/No)

122. Alarm acknowledgment capability (Yes/No)

123. Ability to display phasor and frequency plots in tiled windows with vertical and horizontal option through selection panels for:

a. Voltage Phase Angle Graphs (Yes/No)

b. Voltage Graphs (Yes/No)

c. Reference Voltage Phase Angle (Yes/No)

d. Frequency Graphs (Yes/No)

e. Current Phasor Graphs (Yes/ No)

f. Active Power Flow Graphs (Yes/No)

g. Reactive Power Flow Graphs (Yes/No)

h. $\Delta f/\Delta t$ Graph (Yes/No)

i. Path Active Power Graphs (Yes/No)

j. Path Reactive Power Graphs (Yes/No)

k. Path Current Graphs (Yes/No)

124. Graphs not limited to:

a. Frequency Plot (Yes/No)

b. Voltage Plot (Yes/No)

c. Current Plot (Yes/No)

d. Polar phase angle plot (Yes/No)

e. Rectangular phase angle plot (Yes/No)

f. Active Power Plot (Yes/No)

g. Reactive Power Plot (Yes/No)

h. Δf/Δt Plot (Yes/No)

i. Phase Angle Plot (Yes/No)

125. Path Flows for selected flowgate or corridors(Yes/No)

126. Graphs must have an option to use actual value or deviation from nominal value (Yes/No)

127. Ability to freeze a graph for taking a snapshot (Yes/No)

128. Ability to close and clear a graph (Yes/No)

129. Ability to cascade selected graphs (Yes/No)

130. Support for authoring tools (Yes/No)

B.4.6 Historian Data Server (HDS)

The vendor system should confirm the minimum requirements set forth in this section.

131. There must be a "high-availability" historian for archiving historical synchrophasor and related data to support SGI operations and applications. (Yes/No)

132. The data retention for this historian is X-year. (Yes/No)

133. Fault tolerance can be provided in various ways, but must be compatible with the inter-site failover architecture. (Yes/No)

134. There is also a requirement for long-term (X-year) storage for the corporate users. (Yes/No)

135. Ability to provide services to SGI users and a number of non-SGI users while ensuring that the security and performance of the other component systems of the SGI are not impacted. (Yes/No)

B.4.7 Real-Time Data Server (RTDS)

The vendor system should confirm the capabilities set forth in this section.

136. There must be a "high-availability" historian within the Information Storage to directly support SGI operations and applications. (Yes/No)

137. The data retention for this historian is a minimum of X-year online. (Yes/No)

138. Fault tolerance can be provided in various ways, but must be compatible with the inter-site failover architecture. (Yes/No)

139. There is also a requirement for long-term (X-year) storage for the corporate users. It shall service SGI users and a number of non-SGI users while ensuring that the security and performance of the other component systems of the SGI are not impacted. (Yes/No)

B.4.8 External Data Proxy Services (EDPS)

External data proxy services subscribe to weather, traffic, earthquake, fire, and lightning indicator data provider sites. It retrieves, synchronizes and provides these data to be stored in both Real-Time and Historian SGI databases. Vendor system should confirm to minimum requirements stated below.

EDPS Input

140. Request from Data Management to subscribe to and retrieve weather, traffic, earthquake, fire, and lightning indicator data from provider sites. The procedure will be similar to current NYISO subscription and data retrieval to ISO OASIS via certified URL. (Yes/No)

141. Weather, traffic, earthquake, fire, and lightning indicator data from provider sites. (Yes/No)

EDPS Output

142. Weather, traffic, earthquake, fire, and lightning indicator data per zone to SGI Real Time data base. (Yes/No)

143. ISO published data from OASIS, ADS, and CMRI may also be retrieved and stored. (Yes/No)

EDPS Services

144. Periodic data request to weather, traffic, earthquake, fire, and lightning indicator data provider sites. (Yes/No)

145. Retrieving weather, traffic, earthquake, fire, and lightning indicator data. (Yes/No)

146. Managing and synchronizing received data per defined zones. (Yes/No)

B.4.9 External Systems

Following are key external systems with which SGI is expected to be interfaced.

External PDCs (EPDC)

147. External PDCs are owned by generation, transmission, external ISO PEPMs, and other ISO PDCs which by agreement must be able to provide streamed synchrophasor

PMU data to PDAC at a rate of 30 samples per second in IEEE C37.118-2005 format. (Yes/No)

148. External PDACs/PDCs must be able to receive streamed synchrophasor data from PDAC by agreement at a rate of 30 samples per second in IEEE C37.118-2005 format. (Yes/No)

149. External PDCs must be able to communicate with PDAC directly through a planned ISOnet or through NASPInet (if available) using a Phasor Gateway installed at NYISO GCC. (Yes/No)

EPDC Input

The number of streamed data input from EPDCs depends on the number of EPDCs connected to the ISOnet or NASPInet that NYISO has agreement with. Each EPDC shall send only one data stream to PDAC in IEEE C37.118-2005 format. Data volume for each EPDC is determined by the number of PMUs connected to each EPDC, the number of measurement points of each PMU, and/or the measurement data that NYISO has agreement with. Data volume estimation could be based on NYISO's DFR/PMU with the maximum measurement configuration for each unit. All ISO member utilities should be assumed to have one EPDC each.

150. EPDCs shall provide the configuration information of the streamed data to PDAC upon PDAC's request. (Yes/No)

151. The request and sending configuration information shall conform to IEEE C37.118-2005 format. (Yes/No)

EPDC Output

152. PDAC shall provide data streams to EPDCs that NYISO has agreement with. PDAC will send one data stream to each EPDC in IEEE C37.118-2005 format. (Yes/No)

153. PDAC shall provide data stream configuration information to an EPDC upon receiving the request from the EPDC. The request and sending configuration information shall conform to IEEE C37.118-2005 format. (Yes/No)

Appendix C – Applications

C.1 Voltage Phase Angle Monitoring (VPAM)

A dedicated application will be specified to observe the phase angle differences between any two buses in the system where PMUs are installed. The VPAM application capabilities should be functionally defined by the following:

1. The application should be capable of handling the digital phasor data from PDC or real-time storage in floating point format. (Yes/No)
2. The application should be able to extract the magnitude and phase information for different quantities like voltage and current or any other quantities separately. (Yes/No)
3. The calculation of phase difference between two such data sources can be selected by the System Dispatcher. The application routine would calculate the difference in the phase angles between the selected bus data and store in appropriate register to be accessed by other programs for visual display in the control center or stored in a real-time database. (Yes/No)
4. The application should be capable of converting between degree and radian from the selection of operator. The maximum and minimum phase angle differences are to be specified as input from the operator. The maximum and minimum phase angle differences are to be used in the application to identify potential angle stability problem. (Yes/No)
5. Provisions should be made to be selected by operators to either observe phase angle differences of voltages or currents at each sampling period or every N data points, where N will be specified by NYISO. This down sampling may be done with filters or without any filter. (Yes/No)

The objective of voltage phase angle monitoring will be to provide sufficient information to the System Dispatcher to evaluate the present angle differences between two selected locations. The voltage phase angle monitoring application must have the ability to deliver real-time voltage angle monitoring with alarms and on-line/off-line visualization features such as:

6. Phase angle difference between selected measurement locations (Yes/No)
7. Topological phasor display (Yes/No)
8. Polar diagrams (Yes/No)
9. Strip charts (Yes/No)

10. Any combination of above outputs (Yes/No)
11. The real-time output should provide:
    a. Display of phase angle difference between selected locations in real time (Yes/No)
    b. Display of the phase angle curve at selected locations as a trend (Yes/No)
    c. Display of the maximum acceptable phase angle between two selected locations (Yes/No)
    d. Online warning and emergency alerting (Yes/No)
12. The off-line output should provide:
    a. Access to historical data (Yes/No)
    b. Data export to business applications such as EXCEL (Yes/No)
13. For events:
    a. Angle difference should be included as part of on-line warnings and alarms. (Yes/No)

C.2 Voltage Stability Monitoring (VSM)

The objective of voltage stability monitoring is to have the ability to assess the present power margin with respect to voltage stability. The VSM application should be functionally defined by the following:

1. Monitor the PV and QV-curves with respect to:
    a. Actual loading (Yes/No)
    b. Point of maximum loadability (Yes/No)
    c. Power margin (Yes/No)
2. Provisions should be in the application to calculate Thevenin equivalent impedance and load impedance. (Yes/No)
3. Extraction of Jacobians for PV and QV calculations to text format and to MATLAB, (Yes/No)

PMU measurements should be Global Positioning System (GPS) synchronized at both ends of the lines to deliver values in real-time. This should provide voltage and current phasor information at both ends of the line for System Dispatchers along with calculated values for active, reactive power flow and the direction of the applicable power flow.

The online output should provide:

4. Display of PV-curve with indication of actual loading point (Yes/No)
5. Voltage and current monitoring along a flowgate. (Yes/No)
6. Calculation and display of actual power margin. (Yes/No)
7. Display of the voltage and current phasors at both ends of the transmission corridor. (Yes/No)
8. Display of natural loading point and nominal loading point. (Yes/No)
9. Display of the actual active and reactive power flow. (Yes/No)
10. Display of the direction of the active power transmitted through a corridor. (Yes/No)
11. Display of the equivalent impedance of the load area. (Yes/No)
12. Data logging and trend display. (Yes/No)
13. Online warnings and alarms. (Yes/No)

Offline should provide:

14. Access to historical data. (Yes/No)
15. Data export to business applications such as EXCEL. (Yes/No)

C.3 Low Frequency Oscillation Monitoring (LFOM)

The detection and display of low frequency oscillation in the system is to be supplied by the application vendor. This helps in identifying the critical poorly damped modes such that the operator can make decisions on re-dispatch or some other means to alleviate the small signal stability problem. The LFOM application should be functionally defined by the following:

1. The application should have provisions to identify the modal content of measured signals such as voltage magnitude phasor, current magnitude phasor or phase angle differences. (Yes/No)
2. Modal content comprised of frequency of oscillation of critical modes less than certain frequency to be specified by NYISO, corresponding damping of such modes and amplitude of such oscillations. (Yes/No)
3. Provisions should be in the application to identify a growing oscillation and generate warning and alert messages. (Yes/No)

4. The modal identification is to be performed either at each sampling time or at every N sampling as specified by NYISO. Options are to be provided in the application to select refresh rate of such calculations by the operator. (Yes/No)
5. What is the required calculation time for this application? _____
6. The application should be able to send data streams to other visualization applications in a standard format. The data stream should contain frequency, damping and oscillation amplitude information of each oscillating mode observed in the PMU data, the time stamp information and any warning or alert messages. (Yes/No)
7. The application should also consist of tools to do modal analysis offline with historical data, model validation in linear domain and other linear analysis tools. (Yes/No)
8. The application should be user friendly with helping tools and straight-forward to operate. (Yes/No)

The online outputs should be functionally defined by the following:

9. Oscillation magnitude, frequency of oscillation and corresponding damping of each mode within the specified frequency range for the selected measurement. (Yes/No)
10. Polar diagrams. (Yes/No)
11. Strip charts. (Yes/No)
12. Bar charts with different colors for different modes. (Yes/No)
13. Continuous visual display of movement of the modes in complex plane. (Yes/No)
14. Display of the amplitude, frequency of oscillation and corresponding damping for the selected measurements at selected locations as a trend. (Yes/No)
15. Display of minimum damping criteria to be provided by NYISO in different plots. (Yes/No)
16. Online warning and emergency alerting for lower than minimum damping. (Yes/No)
17. Any combinations of above can be selected for multiview display. (Yes/No)

The off-line output capabilities include:

18. Access to historical data. (Yes/No)
19. Data export to business applications such as EXCEL. (Yes/No)
20. Data export to csv format and text format. (Yes/No)
21. MATLAB interface. (Yes/No)

The event management function should provide:

22. Warning and alarm for growing low frequency oscillation or poor damping with appropriate identifiable colors and information of the mode. (Yes/No)

C.4 Fault Location

C.4.1 Faulted Lines Identification

The faulted lines identification function is used to quickly and positively identify the line sections that just experienced either a temporary or permanent fault.

1. The function shall be able to use network breaker switching indication, relay operation indication, and/or DFR notifications to positively identify the faulted lines within 2 seconds after a fault occurrence. (Yes/No)
2. The function shall use the results of breakers reclosing operations to indicate whether the fault is a temporary fault or a permanent fault. (Yes/No)
3. The function shall indicate whether there were any previous faults on the same line in the last hour, last 24 hours, last 15 days, and last 12 months. (Yes/No)
4. The function shall initiate the fault recording retrieval process to retrieve fault records from DFRs for identified faulted line(s), and then start the fault location calculation function for identified faulted line(s). (Yes/No)

C.4.2 Fault Location Calculation

The fault location calculation function is to provide calculated or estimated fault location information for faulted lines after these lines are positively identified.

5. The fault location calculation function shall be able to complete the fault location calculation or estimation within 5 seconds after the fault occurrence. (Yes/No)
6. The function shall be able to perform the fault location calculation or estimation on each identified faulted line where fault recordings from at least one end of the line are available. (Yes/No)
7. The function shall provide multiple fault location calculation and estimation methods for users to select. (Yes/No)
8. The function shall support fault location calculation or estimation using either synchronized or non-synchronized fault records. (Yes/No)
9. The function shall support fault location calculation or estimation using either single-end method or multi-end method. (Yes/No)

10. The function shall be capable of indicating the type of fault, such as symmetrical or non-symmetrical, phase(s) involved in the fault, and the estimated fault resistance for ground faults. (Yes/No)

C.4.3 Fault Location User Interface

The fault location function user interface shall provide all the flexibility to set up parameters for both manual and automated fault location calculation while minimizing the amount of manual entry. To perform fault location while minimize the amount of manual entry, the fault location function user interface shall support the following:

11. Making use of or re-define default values. (Yes/No)
12. Setting up automatic execution of fault location function. (Yes/No)

C.4.4 Execution Procedures

Fault location function shall always be started automatically upon SGI receiving one or more of the following:

13. Breaker switching operations notification. (Yes/No)
14. Relay operations indication. (Yes/No)
15. DFR new record notification. (Yes/No)
16. SGI shall also be able to invoke the fault location function manually for calculating a line's fault location. In this case, users shall be able to select a line and select the fault location calculation method to be used to start the fault location calculation. (Yes/No)

C.5 Post-Event Analysis

Post-event analysis should have the ability to demonstrate power system replay for post-event analysis. Additionally, it should efficiently handle PMU data related to an event. The PEA application should be functionally designed to accommodate, at a minimum, the following:

1. Retrieve archived records. (Yes/No)
2. Tolerate data being delivered to archives up to one hour late. (Yes/No)
3. Ability to recover protocols that move data to archive after connectivity failures. (Yes/No)
4. Keeping data on demand for a specified period (week, month or year). (Yes/No)
5. Ability to "reverse video" or "highlight" important data lines. (Yes/No)
6. Be accurate enough to buffer all levels of architecture. (Yes/No)

7. Ability to handle chain-of-custody. (Yes/No)
8. PMU configuration data availability along with the data rate. (Yes/No)
9. Event analysis should be time synchronized with high sample rate data. (Yes/No)

C.6 DFR Records Retrieval

1. DFR records retrieval system should have the capability to provide both continuous and long-term recording. (Yes/No)
2. Continuous recording should have the ability to retrieve information up to 100 days that comply with NERC standards:
    a. PRC-002-1 (Define Regional Disturbance Monitoring and Reporting Requirements) (Yes/No)
    b. PRC-018-1 (Disturbance Monitoring Equipment Installation and Data Reporting) (Yes/No)
3. Long-term recording should have logs of signals, power and frequency. Programmable record length should be at least 90 days. (Yes/No)
4. For high speed fault recording the following specifications are required:
    a. Pre-fault Period – up to 10 seconds with a default setting of 10 cycles (Yes/No)
    b. Post-fault Period – maximum post-fault continuous data streaming needs to be provided ____ (Yes/No)
5. DFRs should have the capability to record data simultaneously in three domains:
    a. High Speed Transient Fault that can record more 350 samples/cycle (Yes/No)
    b. Low Speed Dynamic Swings that can record up to 30 minutes (Yes/No)
    c. Continuous Trend from 10 seconds to an hour (Yes/No)
6. The DFR records retrieval system should be designed with a recorder, analog input isolation modules and GUI software. The system should additionally be capable of feeding into Disturbance Monitoring Equipment (DME) with the ability to capture record disturbance data per NERC Standard PRC-018. (Yes/No)

C.7 Global DFR Event Trigger Management

1. A wide variety of triggers should be available to initiate event recording. (Yes/No)
2. The system should have various input analog modules to interface to signal sources. Modules connected to standard signals at the substation are normally:

a. Secondary AC voltage (Yes/No)

b. Secondary AC current (Yes/No)

c. Low level DC voltage and current signals (Yes/No)

3. The GUI software should available to configure the trigger management system to accept these signals. (Yes/No)

C.8 Wide-Area Event Detection (WED)

Wide-area event detection is a part of situational awareness, particularly in the knowledge of device statuses, both locally and over the wide area. Detecting and identifying significant switching events on the system can help system dispatchers understand and react to problems on the grid. The WED application should be functionally designed to accommodate, at a minimum, the following:

1. Measurable quantities that can be used for wide-area event detection should include:
   a. Line impedances and ratings (Yes/No)
   b. Pre-event and wide-area topology information from the NERC System Data Exchange (NERC SDX) (Yes/No)
2. Wide area measurements from PMUs
   a. Wide-area events detection must be capable to what change in angles will be used in power flow equations, ability to detect single and double line outages. (Yes/No)
   b. The detection process should detect events based on PMU measurements using currently available data. (Yes/No)
3. Other important wide-area event detection should include:
   a. Comprehensive of voltage angles and magnitudes (Yes/No)
   b. Monitor angles relative to a specific reference (Yes/No)
4. Identifying Over and Under voltage regions within a specific area (Yes/No)

C.9 Wide Area Situational Awareness

1. Is there a situational awareness application provided with the software?
2. How many PMU and DFR devices can be accommodated in your WASA application?
3. How much disk space the module needs?

4. How much computer processing time is needed to process each PMU data?
5. Is a network model needed for the WASA application?
6. Does the WASA application provide functionalities of
    a. Real-time grid view with geographical locations?
    b. Voltage, current, power and other relevant measurements at each critical locations?
    c. Monitor phase angle differences at different critical regions?
    d. Assessment of voltage stability?
    e. Detection of System oscillations, frequency of oscillation, damping?
    f. Fault location detection?
7. Does the WASA application provide multi-view of grid conditions with topological diagram?
8. Does the application need any data from other applications?
9. What communication protocol is used to exchange data between applications?
10. What is the cost of the WASA application?
11. What are the license terms and conditions?
12. How frequent an upgrade is available?
13. What are the inputs and outputs of the WASA application?

C.10 Voltage Stability

1. Does the application provide a module for voltage stability prediction?
2. Where does the voltage stability application reside, PDC level or Master PDC level?
3. How many computer systems are needed?
4. What is the memory requirement for the application?
5. How much CPU time is used for this application?
6. Provide summary of the algorithm used to predict voltage stability.
7. At what frequency is the voltage stability algorithm is run (i.e., for each sample of the PMU data or at certain interval)?

8. Does the application need a system model for this application?
9. Can the application provide PV, QV curves for output display?
10. Is it possible to select a particular bus or region for voltage stability analysis?
11. What communication protocol is used to send or receive data for the application?
12. Is the voltage stability application capable of sending or receiving data from any other applications?
13. Is it possible to run the voltage stability analysis both online (in real time) and offline?

C.11 State Estimation (EMS)

1. What is the minimum time interval between two consecutive state estimation calculations?
2. How much is the processor usage for each state estimation calculation?
3. How many computer workstations are needed for the application?
4. Is the EMS capable of receiving and utilizing PMU data?
5. What is the protocol used for data communication between PDC and EMS server?
6. Is the EMS capable of multiview graphical user interface (GUI)?
7. Is the EMS interoperable with other vendor's supplies?
8. What are the main functionalities of the EMS application?
9. Does the application need any data from other applications?
10. What communication protocol is used to exchange data between applications?
11. What is the cost of the EMS application?
12. What are the license terms and conditions?
13. How frequent is an upgrade available?
14. What are the inputs and outputs of the FRF application?

C.12 Calibration and Validation of NYISO's System Models

1. Does the vendor have an application for calibration and validation of system steady-state model?

2. Does the application need PMU data?
3. Does the application need EMS –SCADA data?
4. Does the application need RTU data?
5. What algorithm is used to identify the steady-state parameters for NYISO model?
6. Can the application be run in real-time?

C.13 Calibrate and Validate of NYISO's Dynamic System Models

1. Does the vendor have an application for calibration and validation of system dynamic model?
2. What are the main parameters that are validated through the application?
3. Does the application need PMU data?
4. Does the application need EMS –SCADA data?
5. Does the application need RTU data?
6. What algorithm is used to identify the dynamic parameters of the NYISO model?
7. Can the application be run in real time?
8. Does the application need any data from other applications?
9. What communication protocol is used to exchange data between applications?
10. What is the cost of the application module?
11. What are the license terms and conditions?
12. How frequent is an upgrade available?
13. What are the inputs and outputs of the application?

Appendix D – Capacitor Equipment

The focus of the questions in this section is to provide the latest understanding of controllers and associated software for Smart Grid enabled capacitors.

1. Describe the capacitor control products along with the associated software.
2. Are the controllers designed to handle Distribution (pole or pad mounted or station) or Transmission (station) connected capacitors?
3. Does the controller meet the cyber security requirements? Hardened?
4. Describe the command and control functions.
5. Describe the communication capability/technologies and protocol options supported? Single, two-way or both? Is the controller and communications separate or a single device? What is the voltage required to run the communications?
6. Do you envision connecting directly to a PDC?
7. Is the device remotely controllable? If yes, can the device be remotely overwritten? For example, the capacitor can be set to switch on and off based on a voltage or current or reactive set point. Can the set point be over written, over ridden, or re-programmed remotely?
8. Are any sensors required on pole or pad-mounted capacitors? If yes please describe.
9. How is the "status" of the capacitor switch confirmed?
10. Is the product upgradable? Hardware and Software?
11. Describe the data access, logging, and graphic capability.
12. How is "bad" data dealt with and/or adjusted?
13. Describe the mounting options.
14. How many capacitors/banks can be supported with a single controller?
15. Describe the set up and configuration process.
16. What is the lead time to acquire product?
17. Can the input and output of the controller be integrated with other transmission and distribution capacitor controllers?

Appendix E – Cyber Security

1. Has your company done any business with either the US Federal Government or State Government?
    a. Specifically have you done business with either the US DoE or DOD to provide any Smart Grid technologies?
2. What industry, federal or technical standards are your products currently compliant with?
3. How do you assure that your products remain compliant with industry, federal or technical standards?
4. Do you participate in any of the standards bodies (NIST, IEEE, IEC, etc…)?
5. What safeguarding procedures are deployed within your manufacturing that can provide assurance that individual components of your product are not tampered or compromised by your supply chain?
6. What is your schedule for standard release time frames for security patches and firmware upgrades?
7. What safeguarding procedures do you have in place regarding personnel background checks?
8. What types of maintenance/support agreements do you provide customers?
9. What encryption mechanisms are available within your products for data as it's transferred and at rest?
10. Please provide a description of the remote access (centralized management) capabilities of your products.
11. What kinds of authentication mechanisms are available within your product?
12. What kind of authorization and roles based access is supported by your products?
13. Does your product support event notification or alerting to commonly used Security Event Incident Management (SEIM) products?
14. What kinds of logging formats are available within your products?

Appendix F – Testing

1. Can the supplier provide detailed tests plan/s, including all simulation/design verification tests (if applicable), factory tests, site acceptance tests and commissioning tests? (Yes/No)
2. Is it possible to have all inspection and test procedures agreed upon before PO? (Yes/No)
3. Are the tests comprehensive enough to prove compliance with all technical requirements? (Yes/No)
4. Will the supplier provide inspection and test witness points during the manufacture, assembly, and testing activities for the equipment (including subcontracted components)? (Yes/No)
5. Does the supplier have testing procedure to ensure all anticipated vulnerabilities are addressed and no new vulnerabilities have been introduced?
6. Will the supplier agree to a consultant to witness the factory/site acceptance tests, review simulation tests and results.
7. The Testing should include at minimum the following:
    a. Standards compliance. (Yes/No)
    b. Design verification simulation. (Yes/No)
    c. Functional test plan. (Yes/No)
    d. Integration/interface with existing equipment. (Yes/No)
    e. Protocol compliance. (Yes/No)
    f. Environmental
        i. Electrical (Yes/No)
            1. Transients (Yes/No)
            2. Insulation (Yes/No)
            3. EMI/RFI (Yes/No)
        ii. Mechanical
            1. Vibration (Yes/No)

2. Temperature (Yes/No)

3. Humidity (Yes/No)

g. Cyber security. (Yes/No)

h. Interoperability with other equipment. (Yes/No)

i. Device performance validation. (Yes/No)

j. System performance validation. (Yes/No)

8. Tests procedures should include:

a. Inspection or test objectives. (Yes/No)

b. List of components to be inspected or tested, referring to specification item/standards used (ANSI, ASTM etc.). (Yes/No)

c. Criteria for inspection or test acceptance and rejection. (Yes/No)

d. Test configuration. (Yes/No)

e. Test prerequisites. (Yes/No)

f. Description of testing facility. (Yes/No)

g. Authorities and responsibilities for conduct of tests and approval of test results. (Yes/No)

h. Description of test equipment. (Yes/No)

i. Listing of all data to be observed and recorded. (Yes/No)

Supplemental A – Communication Protocols

(To be completed when additional information is provided by NYISO.)

The following describes the data communication protocols currently in use throughout the industry. Note that this list of protocols is subject to change considering the Smart Grid Architecture blueprint and the SGI requirements discussed in this System Design document.

Communication Requirements – General

The major requirements are:

1. Interoperability - Open Data Access - Remote Control
2. Self-Defining Devices - Automated Reports - Substation Events Handling
3. Time Sync - Network Management - Security/Integrity
4. Expandability - Extensibility - Easy of Maintainability
5. Independent Functional Structure (Media_Transmission_Applications)
6. Protective Function Response Time Capability
7. Peer-to-peer communications

Following is a list of required protocols. Although Object-Oriented Protocol technologies lack established standards, the design must be open to adapt such technologies.

- Products can communicate over Generic Object Oriented Substation (GOOSE): (Yes/No)
- Products can communicate over OPC: (Yes/No)
- Products can communicate over ModBus: (Yes/No)
- Products can communicate over Distributed Network Protocol (DNP): (Yes/No)
- Products can communicate over Inter Control Center Protocol (ICCP): (Yes/No)

Supplemental C – Glossary

Acronym	Description
AES	Advanced Encryption Standard
AGC	Automatic Generation Control
AMI	Advanced metering infrastructure
ARRA	American Recovery and Reinvestment Act
BES	Bulk electric system
CA	Contingency analysis (an operational planning tool to analyze impacts of contingencies such as line and terminal outages on the power grid performance)
CCPDC	Control center phasor data concentrator
CCS	Control center system
CES	Core Enterprise Services (a set of common IT services for multiple information systems and applications in NYISO)
CIM	Common Information model (IEC 61970)
CIP	Critical infrastructure protection
C-RAS	Centralized remedial action scheme, where remedial actions are coordinated centrally using high-speed data transmission from relays and other IEDs from their field locations to a central engineering station
CRC	Cyclic redundancy check
DA	Distribution automation
D/B/A	Doing Business As
DER	Distributed energy resources
DFR	Digital fault recorder
DFRR	Digital fault recorder records retrieval
DG	Distributed generation
DME	Disturbance monitoring equipment
DMS	Distribution management system
DNP	Distributed network protocol
DOE	Department of energy (USA)
DR	Demand response
DSM	Demand side management
DW	Data warehousing
EDPS	External data proxy services
EMS	Energy management system
EPDC	External PDC, (PDCs that are external to NYISO that could share synchrophasor data with NYISO)
FL	Fault location
GCC	Grid control center
GCCN	The dedicated communication network for the NYISO Grid Control Center
GIS	Geospatial Information System
GOOSE	Generic Object Oriented Substation Events
GPS	Global Positioning System

Acronym	Description
GUI	Graphical User Interface
HDS	Historian data server
HMAC	Hash message authentication code
HMI	Human Machine Interface
HTTP	Hyper Text Transfer Protocol
ICCP	Inter control center protocol
IED	Intelligent electronics devices, such as digital relays
IEEE C37.118	IEEE standard for synchrophasors for power systems
IP	Internet protocol
IP	Intellectual property
IPP	Independent power producer
IPv4	Internet Protocol version 4
Ipv6	Internet Protocol version 6
LFOM	Low Frequency Oscillation Monitoring
LIPA	Long Island Power Authority
MD3i	Model-Driven Information, Integration, and Intelligence (Xtensible methodology)
MPLS	Multiprotocol Label Switching, a mechanism in high-performance telecommunications networks with “virtual links” between distant nodes and ability to encapsulate packets of various network protocols
MS	Master station
NASPI	North American Synchrophasor Initiative
NASPInet	NASPI network, a high-speed, high-availability and highly secure data communication network and IT infrastructure to enable synchrophasor data sharing across North America
NERC	North American Electric Reliability Corporation
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPA	New York Power Authority
PDAC	Phasor Data Acquisition and Control
PDC	Phasor Data Concentrator
PDAC	Phasor Data Acquisition and Control Subsystem
PEA	Post-Event Analysis
PME	Phasor Measurement Equipment
PMN	Phasor Measurement Network
PMU	Phasor Measurement Unit
PSA	Power system analysis
QoS	Quality of service
RAS	Remedial action scheme
RFI	Request for Information
RFP	Request for Proposals
RT	Real-time
RTDS	Real-time data server
SCADA	Supervisory control and data acquisition
SDM	System and data management
SE	State estimator (an EMS application to estimate states of the power grid based on points where measurements are available)
SEIM	Security Event Incident Management
SGI	Smart Grid Infrastructure

Acronym	Description
SMART	Synchronized measurement and analysis in real-time
SMU	Synchronized Measurement Unit
SOA	Service Oriented Architecture
TO	Transmission Owner
SOAP	Simple Object Access Protocol
SPDC	Super Phasor Data Concentrators
TCP	Transport control protocol
UDP	User datagram protocol, a simple protocol used in the Internet, a core member of the Internet Protocol (IP) suite; unlike TCP, UDP is compatible with packet broadcast (sending to all on local network) and multicasting (send to all subscribers)
VPAM	Voltage Phase Angle Monitoring
VS	Visualization server
VSM	Voltage stability monitoring
WAC	Wide-area control
WAM	Wide-area monitoring/measurement
WAMPACS	Wide-area monitoring, protection and control system
WAP	Wide-area protection
WDSL	Web services description language
WED	Wide-Area Event Detection